



Porosity, permeability and 3D fracture network characterisation of dolomite reservoir rock samples

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ARTICLE INFO

Article history:

Received 5 August 2014

Accepted 16 December 2014

Available online 31 December 2014

Keywords:

μCT
computed tomography
image processing
aperture
permeability
confining pressure

ABSTRACT

With fractured rocks making up an important part of hydrocarbon reservoirs worldwide, detailed analysis of fractures and fracture networks is essential. However, common analyses on drill core and plug samples taken from such reservoirs (including hand specimen analysis, thin section analysis and laboratory porosity and permeability determination) however suffer from various problems, such as having a limited resolution, providing only 2D and no internal structure information, being destructive on the samples and/or not being representative for full fracture networks. In this paper, we therefore explore the use of an additional method – non-destructive 3D X-ray micro-Computed Tomography (μCT) – to obtain more information on such fractured samples. Seven plug-sized samples were selected from narrowly fractured rocks of the Hauptdolomit formation, taken from wellbores in the Vienna basin, Austria. These samples span a range of different fault rocks in a fault zone interpretation, from damage zone to fault core. We process the 3D μCT data in this study by a Hessian-based fracture filtering routine and can successfully extract porosity, fracture aperture, fracture density and fracture orientations – in bulk as well as locally. Additionally, thin sections made from selected plug samples provide 2D information with a much higher detail than the μCT data. Finally, gas- and water permeability measurements under confining pressure provide an important link (at least in the order of magnitude) towards more realistic reservoir conditions.

This study shows that 3D μCT can be applied efficiently on plug-sized samples of naturally fractured rocks, and that although there are limitations, several important parameters can be extracted. μCT can therefore be a useful addition to studies on such reservoir rocks, and provide valuable input for modelling and simulations. Also permeability experiments under confining pressure provide important additional insights. Combining these and other methods can therefore be a powerful approach in microstructural analysis of reservoir rocks, especially when applying the concepts that we present (on a small set of samples) in a larger study, in an automated and standardised manner.

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1. Introduction

Fractured reservoirs constitute a significant part of the world's hydrocarbon potential. As pointed out by Nelson (2001), the presence and topology of natural fractures in reservoirs have been and are too often ignored or oversimplified in their interpretation, leading to wrong decisions in exploration and production plans. Natural fractures cannot only contain significant volumes of hydrocarbons (connected

porosity), but are in many reservoirs vital for allowing flow at sufficient rates for production (permeability), so analysing and understanding the complexity of fractures and fracture networks is crucial. Nelson (2001) and Aguilera (1995) have given excellent overviews of fractured reservoirs, their characteristics, and their analysis over a wide range of geological scales. In this paper, we will focus on fracture analyses at the scale of drill cores and plugs, and some common analyses will be discussed first.

After recovery, initial research on drill cores and plugs is mostly done at hand specimen scale, in the form of core logs. At this scale, for example composition, fracture density and orientation can be determined, and may sometimes be compared to features observable at the scale of borehole logs and borehole imaging logs (e.g. microresistivity by Formation MicroImaging (FMI), Ekstrom et al.

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(1987), Prenskey (1999)). However, the resolution of the above techniques is limited, and no details about the internal structure of the reservoir rocks can be obtained.

After hand specimen analysis, cores and smaller drilled out plugs are selected to determine their (among others) porosity and permeability, using standardised methods in the laboratory (e.g. API, 1998; Andersen et al., 2013). Such laboratory measurements are also used in this study, but as they provide bulk values only, no information about the internal structure of a core or plug sample is obtained. Some laboratory methods like Mercury Intrusion Porosimetry (MIP; e.g. Klobes et al., 1997; API, 1998; Andersen et al., 2013) do provide information about the internal structure of samples, but are invasive in nature, and samples may not be suitable anymore for other analyses afterwards.

Following bulk laboratory measurements, thin section analysis on drill core samples and wall cuttings can be carried out, if a more detailed analysis of their internal structure is required (e.g. Anselmetti et al., 1998; Gale et al., 2004). Thin sections provide very detailed, generally two-dimensional views of the microstructure of the rocks, and are therefore still an important part of our research. However, creating thin sections is destructive on the original samples, and the 2D view can be limiting, especially when looking at fracture networks.

Finally, several (less common) analyses can potentially be carried out to characterise fractures on the core and plug scale. For example, fracture surface, fracture roughness and fracture aperture have been analysed in the past using varying methods (for example by physical and optical surface profiling, Plouraboué et al., 1995; Kulatilake et al., 2008; Sharifzadeh et al., 2008; Isakov et al., 2001; Neuville et al., 2012; overview of methodologies in Hakami et al., 1995). These methods are very detailed and are usually only applied on single (often artificially created) fractures, so are not well applicable on fracture networks. Another option is to generate theoretical models of fracture networks, by applying stochastic methods to create fractures with realistic spacing, connectivity, aperture and flow properties (for example Discrete Fracture Networks, e.g. Singhal and Gupta, 2010; Sahimi, 2011). Such methods are especially useful at the reservoir scale, but may not be fully representative for the actual situation and complexity found in nature, and they still require realistic input data (e.g. obtained by the methods listed before).

The mentioned methods of conventional research on fractured core and plug samples thus all have at least one of the following drawbacks: (1) a limited level of detail for fracture characterisation, (2) limited or no information on the internal structure, (3) two-dimensional information only, (4) destructive on the samples, (5) not applicable on, or not representative for full fracture networks. A good candidate for overcoming these drawbacks is X-ray micro-Computed Tomography (μ CT), which allows us to non-destructively image samples in 3D in detail, and thereby allows us to extract properties that otherwise would remain uncovered (for example fracture connectivity, fracture aperture, fracture orientation). Although the use of μ CT has its own drawbacks and limitations (discussed later), it provides a good compromise between the 5 drawbacks mentioned above, especially when complemented with other analytical methods.

CT and μ CT are nowadays commonly used in various branches of geosciences. For an overview on (μ)CT scanning, applications in the geosciences, and important parameters and processing steps to consider, the reader is referred to Ketcham and Carlson (2001), Mees et al. (2003), Cnudde et al. (2006) and Kaestner et al. (2008). Quite some (μ)CT research has been carried out on samples containing fractures (e.g. Keller, 1998; Bertels et al., 2001; Van Geet and Swennen, 2001; Sellers et al., 2003; Muralidharan et al., 2004; Karpyn et al., 2007; Zabler et al., 2008; Wennberg et al., 2009; Watanabe et al., 2011; Ellis, 2012). These papers cover a wide

range of lithologies, scales, and (μ)CT processing and analysis routines. Unfortunately, they focus only on single fractures or relatively simple combinations of fractures. (μ)CT has occasionally been applied on more complex (natural) fracture networks, with some examples in literature: on building materials (Landis et al., 2003; Ehrig et al., 2011), coals and clays (Montemagno and Pyrak-Nolte, 1999; Bossie-Codreanu et al., 2004; Lenoir et al., 2007) as well as on carbonates (Christe, 2009; Barnhoorn et al., 2010; Zalewska et al., 2011; Fusi and Martinez-Martinez, 2013; Jia et al., 2013). One of the main obstacles throughout this literature is the efficient 3D processing and analysis of fractures, and especially of narrow fractures. An important focus of this study lies therefore on the extraction of narrow fracture networks and other porous structures from μ CT data, using a Hessian-based filtering technique for planar features introduced by Voorn et al. (2013). After this processing step, we focus on the determination of important parameters for the hydrocarbon industry, such as porosity, fracture aperture, fracture density and fracture orientation.

The main question we try to answer here is how to efficiently analyse natural fracture networks in dense rocks, using various methods (2D and 3D imaging, and laboratory porosity and permeability determination), with an emphasis on 3D μ CT. These descriptions will be primarily based on 7 dolomite plug samples from the basement of the Vienna Basin (Austria), with different fracture and porosity characteristics. The above methods are however all applied at surface conditions. To obtain a better understanding of the behaviour of the samples at depth, we also subjected most plug samples to permeability experiments under confining pressure. Combined with the imaging information on structure, this can serve as an important input for permeability and reservoir modelling.

2. Geological background and samples

The rocks analysed in this study originate from the Upper Triassic (Norian) Hauptdolomit (Dolomia Principale in Italian-speaking regions) formation, a major formation present throughout the Alps and built up of mainly dolostone. In literature, the rocks of the Hauptdolomit formation are consistently thought to have formed by syn-sedimentary or very early dolomitisation (e.g. Fruth and Scherreiks, 1984; Blendinger, 1997; Masaryk and Lintnerová, 1997; Antonellini and Mollema, 2000; Meister et al., 2013), and are affected by partial dedolomitisation in some areas (Masaryk and Lintnerová, 1997).

All samples in this study are taken from cores from wells drilled in the pre-Neogene basement of the Vienna Basin (Austria), with the depths of origin listed in Table 1. In the Vienna Basin basement, the Hauptdolomit formation rocks are present in different tectonic nappes of the Northern Calcareous Alps (NCA), with the NCA itself being a component of the larger allochthonous Alpine–Carpathian thrust complex. Both the Alpine nappe stacking in this thrust complex up to the end of the Paleogene, and the formation of the Vienna Basin by pull-apart extension from the Early Neogene (Miocene) onwards, have affected the Hauptdolomit rocks (Zimmer and Wessely, 1996; Arzmüller et al., 2006), leading to a complex dense fracture network over a wide range of scales (Peresson and Decker, 1997). From these densely fractured rocks, hydrocarbon (mainly gas) exploration and production have been successful since the early 1960s (Zimmer and Wessely, 1996). However, some of these reservoirs produce better than others, and the reasons for this are not always well understood. Because several of the wells are quite old (drilled in the 1960s and 1970s), logging information is not as extensive as for more modern wellbores, and is therefore not always useful for detailed microstructural analysis. The information gathered from μ CT imaging

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